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ELECTRICITY NETWORK CHARGING FOR FLEXIBILITY

Michael G. Pollitt

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This paper discusses the principles of electricity network charging in the light of increasing amounts of distributed generation and the potential for significant increases in electric vehicles or distributed electrical energy storage. We outline cost reflective pricing, traditional public service pricing, platform market pricing and customer-focussed business model pricing. We focus on the particular problem of how to recover network fixed costs and a recent example from Australia. We conclude that there are serious issues for regulators to address, but that potential solutions at the distribution level may already exist at the transmission level.



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Electricity Network Charging for Flexibility

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General principles of pricing electricity services

Electricity service involves the delivery of both power (kW), energy (kWh) and power quality (e.g. voltage, frequency, interruptions) at a particular location. Final consumers value each of these attributes directly and it is possible to charge for each of these dimensions of service. Thus connection charges largely reflect the peak power delivery capacity; usage charges significantly reflect energy consumption; and consumers may be willing to accept lower bills in return for more interruptions. Charges do vary substantially by location for many customers, though some types of charge (price) variation have historically not been observed such as price variations among residential electricity customers in the same region.

Electricity pricing is typically for a bundled service where delivery costs and commodity costs are bundled up by the retailer, who handles the contractual relationship with the wholesale power market and the transportation – transmission and distribution – companies. Final consumers mostly prefer such bundling and value the transactions benefits of a single service provider contract and the insurance element that non-exposure to individual cost elements brings. These arrangements have traditionally been common to all network industries.²

¹ The author acknowledges the very helpful comments of Ofgem, Patrick Taylor, David Newbery, Ian Alexander, Gordon McFadzean and one anonymous referee. Any views expressed in the paper are entirely those of the author and should not be taken to be those of any person or organization with which he is associated. The financial support of the EPSRC Business, Economics, Planning and Policy for Energy Storage in Low-Carbon Futures (BEPP-Store) is acknowledged.

² See Oseni and Pollitt (2016) who discuss the historical evolution of residential electricity and fixed line price structures.

Technological developments are challenging the traditional basis of charging in a number of ways. The growth of distributed generation (DG) is changing the nature of the use of the distribution network, traditionally sized for transporting electricity one way from the bulk supply points on the transmission system to end-consumers. The growth of intermittent generation at both the transmission and distribution levels, coupled with the decline of large scale controllable fossil fuel generators, means that new sources of flexibility need to be added to the network, often at the distribution system level. Such flexibility can take the form of automated network management (ANM) of DG, demand side response (DSR) or electrical energy storage (EES).³ The arrival of smart meters (SM) at the household and small and medium sized business level also offers increased possibilities for time and location varying price signals to be sent to end-users and their equipment. The location of DG, DSR and EES - so called distributed energy resources (DERs) - closer to demand, gives rise to the potential to reduce or defer the need for future distribution and transmission system network investment. New sources of demand such as electric vehicles or air source heat pumps offer the possibility of pricing new electricity products such as fast charging for EVs or the bulk purchasing of temperature related electricity, whereby a different price is applied to the new product at the same time as continuing to offer the traditional electricity service product. Electricity consumers can also directly invest in their own DERs and hence can arbitrage between using network provided electricity services and their own production. Furthermore they can sell excess own production on to the grid. Ideally end-users' incentives self-consume or export should reflect true system relative costs and not be large driven by differences in the way network fixed costs are recovered among network users.

It is important to distinguish between the pricing of electricity services to final electricity customers and the pricing of the use of the electricity network services to non-final network users such as traditional generators, DG or EES.

³ See Strbac et al. (2016) for a discussion.

Non-final network users can be exempted from network charges if this reduces whole system costs. Thus if charging for the use of system simply raises the prices charged by DG or EES and this in turn raises the final prices borne by ultimate consumers then it is not obvious that they should be charged. Indeed many electricity systems focus all network charges on the demand side and exempt all sources of generation from charging. There are three good reasons NOT to do this: costs of connection do vary by location and hence one should send signals on where to locate to the DERs; some DER services produce private rather than system wide benefits (e.g. voltage stability in a particular part of the network) and the costs should be targeted on the beneficiaries (who are the ones with the incentive to invest); and generation may be owned by loads who are using the DERs to reduce their contributions to the fixed costs of the network.

In this paper we focus on the particular problem of electricity network charging in the light of these new developments. We begin with a discussion of charging principles; proceed to examine the problem of fixed cost recovery; present a case study of how rapidly distortionary charging can become a material issue; note the potential for over-incentivisation of flexibility; and end with some conclusions.

Four different sets of network charging principles

In this section we outline, compare and attempt to synthesise four different charging principles.⁴ Each represents a particular way of thinking about how to charge for network services in a world characterised by the need to reward flexibility services in such a way as to deliver the electricity services that customers actually want, subject to high level policy objectives on decarbonisation, renewables and demand reduction.

⁴ For a related discussion on the economics of recovering network fixed costs, see Borenstein (2016).

The four basic principles to be reconciled are: cost reflective charging, traditional public service pricing, platform market pricing and customer focussed business model pricing. The first two have historically been closely associated with each other; similarly there is a close relationship between the modern theory of platform market pricing and customer focussed business model pricing.

Cost reflective pricing recognises that electricity network costs vary by time, location and power quality. In theory, network charges should reflect the cost of delivering of import and export capacity to network users. The cost of this capacity should vary by time of day, location and quality and by the amount of capacity itself (and whether it is export or import). For large energy users and large generators connected to the transmission system this is significantly the case already. Indeed in many organised markets in the US, transmission system users are exposed to locational marginal prices for power.⁵ In the past actual prices paid have not varied much by time of day, location or quality for most network users, significantly because of a lack of half-hourly metering. Indeed retailers have explicitly offered a large degree of averaging and wholesale price risk insurance to most final customers. However as we noted above distribution system connected users can increasingly respond to both the short and longer run price signals that more cost-reflective charging would send, because of the presence of smart equipment which can respond to real time signals. This is especially important with respect to flexibility services, which have traditionally been bundled up with the monopoly distribution service, but could be made competitive (e.g. voltage support in the distribution network).⁶

A fundamental issue in cost-reflectivity is whether some of the traditional differences in the basis of network charging – e.g. for low/high voltage distribution level connected generation vs transmission level connected generation – are fit for purpose given the direct competition between the

⁵ See Bohn et al. (1988) and Hogan (1992).

⁶ See discussion of the potentially competitive elements of current distribution service in CEER (2014, especially page 43) and in State of New York Department of Public Service (2014, especially page 20).

services provided by these types of network user. For instance, transmission connected generators in Great Britain are required to pay a per MWh balancing services use of system charge (BSUoS), which is not paid for by DG, while there is no volume related export charge for micro-generators (such as household PV) connected at the distribution level.

Traditional public service pricing has sought to reconcile cost reflectivity and fairness ⁷, while recognising that networks often have public goods characteristics, such as the fact that some dimensions of power quality are common (e.g. system frequency stability). Regulated industries, such as electricity, are regulated precisely because of legitimate public interest in both the average level of and the distribution of charging between customers. Regulators are also tasked with enforcing socially acceptable levels of price discrimination.⁸ Regulated industries have been built up over decades and financed by past customer contributions, the current generation is paying for/benefiting from past network expenditure. Financial commitments entered into previously need to be honoured by the current generation of customers. Perhaps 80% (or more) of current network financial costs are fixed.⁹ And Recovering these costs through network charges is akin to taxation, in the sense that optimal public sector pricing for a monopoly network (see Rees, 1984) would suggest marginal cost pricing, which would leave fixed costs uncovered and the network making a financial loss to be covered by general taxation.

TNEI¹⁰ have estimated that, for one DNO (WPD) in the period 2015-2023, 87% of all expenditure (both capital and operating costs) does not vary with the number of customers or MWhs distributed. For distribution use of system charges (DUoS), as opposed to connection charges, this figure rises to 93%. While some operating costs could be reduced if connections were to fall or planning standards (related to network resilience) were to be relaxed, they could

⁷ This reflects the Bonbright principles of utility rate making (see Bonbright, 1961).

⁸ See Stigler and Friedland (1962).

⁹ Simshauser (2014) suggests that distribution network costs are 60% sunk, 20% fixed and 20% variable in Australia.

¹⁰ <http://www.tnei.co.uk>

probably not be reduced on less than a 5-10 year horizon. This is just with respect to expenditure, there are ALSO sunk costs related to the need to pay returns on past investments. For WPD the opening regulatory capital value, which requires a financial return, implies that 34% of the opening revenue requirement is required simply to finance past investments.¹¹ The situation is similar for the transmission network.¹²

Added to this, some network costs are related to the recovery of government imposed energy policy schemes, bad debt recovery costs and cover insurance costs. Regulators have to approve both the level of prices and the charging methodologies¹³ by which average price or average revenue caps are achieved. Charging very different prices to different households or small and medium sized enterprises (SMEs) in the same area has not been an acceptable form of price discrimination, historically. However some forms of cost reflectivity have been recognised as being important such as time of day pricing for larger users, charging customers in different areas differently, cost reflective connection charges or charging more to customers connected at higher voltages. Going forward, the public service pricing principle may be thought of as giving rise to a form of grandfathered rights of access to the network on a particular charging basis. Careful thought should therefore be given to arbitrary reallocation of existing network access rights, via significant changes to the basis of network charges and to the impact of new users of the network on the existing allocation of payments for network services.

Platform market pricing is about how to price the services provided in a two-sided market¹⁴. The classic example is the credit card company (e.g. MasterCard

¹¹ The opening capital value of WPD in 2015-16 is £5.75bn, which if compensated at 7.5% for 40 years (5% + 2.5% depreciation), would imply annual payment of £431m out of base revenue of £1257m (see <https://www.ofgem.gov.uk/publications-and-updates/decision-fast-track-western-power-distribution>).

¹² At the transmission level locational marginal charges can only recover around 30% of transmission system costs, leaving 70% to be recovered in other ways (see [Perez-Arriaga et al., 1995](#)).

¹³ In Great Britain these are the Common Distribution Charging Methodology (CDCM) and EHV Distribution Charging Methodology (EDCM).

¹⁴ See Weiller and Pollitt (2013).

or Visa) that provides transaction services to retailers and to final credit card users. Normally credit card users are given the cards for free, while the retailers pay transaction related fees, which they can pass on in higher goods prices to the users. MasterCard for example, as the platform provider for their global payments system, coordinate both sides of the market and there exist powerful network externalities, implying that the utility of users of a platform depends on the number of other users - either on the same side or the other side of the platform. ICT and the associated complementary innovation an essential component of platform markets: this creates added-value that increases utility to all user groups.

The electricity distribution network operator can be thought of as platform provider, providing services to both final electricity consumers, conventional generators and to flexibility providers who own DERs. In the future we can imagine energy service companies (ESCOs) placing DER equipment on their customers' premises for free¹⁵, paying the network companies and recovering the costs from the customers in higher energy service charges. DNOs, acting as the platform owner, might want to encourage this by rebalancing their charges away from households and focusing them on ESCOs. The State of New York has explicitly adopted the idea of the distribution utility as a distribution system platform provider (or DSP) for the promotion of DERs.¹⁶ The platform idea should focus consideration of what is the unique service provided by the regulated network and what are the services that are sold across the platform between the two-sides of the market. At a basic level, a transparent and simple platform user charge could serve to promote use of the platform (e.g. by flexibility providers) and more importantly increased overall trading value (as in the credit card example), in a way that finely tuned cost reflective pricing may fail to do.

¹⁵ For instance, Richter and Pollitt (2016) find that household electricity customers would expect the ESCO to pay them for locating DERs on their premises.

¹⁶ See State of New York Department of Public Service (2014), Pollitt and Anaya (2016) and Jones et al. (2016).

Customer focussed business model pricing puts customers and what they value at the centre of charging principles. Business model theory focuses on value proposition, value creation and value capture.¹⁷ Customers are willing to pay for something when it satisfies a need for them (i.e. it has a *value proposition*). A given good or service must involve *value creation* for the customer, by effectively satisfying this need. Finally, there must be some way for service providers to monetise these customer benefits (*value capture*). The key issues for DERs are: do they have a value proposition for ultimate customers; what services to they actually provide to the system; and how can they be remunerated effectively.

There is more than one way for a given DER to be remunerated. Gassmann et al. (2014) identify 55 generic business models (e.g. pay per use, subscription, revenue sharing etc.). In modern markets (e.g. the platform markets mentioned above) with large numbers of service providers and business-to-business (B-to-B) transactions the allocation of value to individual businesses is complex. It is often achieved by exploiting multiple revenue streams. It should be remembered that manipulating network charges to send price signals to DERs is only one of several sources of cost and benefit for DER investors and it may not be decisive or indeed effective¹⁸. It is also the case that DNOs and transmission companies should also be incentivised to innovate uses for their platform and are in a good position to respond to potential future uses of their own networks, subject to a requirement not to disadvantage their current customers.

These four different approaches to network charge determination all recognise the importance of a degree of cost reflectivity, however they put very different degrees of emphasis on this as a charging principle. They also draw attention to where cost recovery should be focussed, on the need fair charging and the promotion of innovation and increased use of networks that have public good characteristics and exhibit network externalities.

¹⁷ See Teece (2010).

¹⁸ See Northern Powergrid (2015), discussed below.

It is also important to be clear that in the end it is very difficult to avoid the distortion created by the difference between consumer and producer prices. This is common to all goods in society. Consumer prices include taxes (VAT, recovery levies, fixed costs), producer prices do not include these. There is always going to be a 'tax' advantage in self-supply. This will tend to undermine the ability to recover fixed costs in conditions where end users are allowed to make investments in their own DERs. The question is how serious this distortion will become and whether moving the recovery of electricity taxes to other elements of electricity service, other than kWhs, will be possible? One example from telecoms, which suggests this is possible, is the emergence of broadband charges as a significant source of revenue for fixed line telecoms providers. The rise of electric vehicles requiring the option of fast home charging might require households to maintain their electricity distribution grid connection and facilitate a fast charging fee which could allow existing per kWh charges to be reduced (or not increased as self-generation rises).

Another possibility is to extend the current charging basis to include own-use of DERs (such as storage and PV).¹⁹ Currently this is straightforward because all own production commands a subsidy payment and hence must be metered and reported. In the future this sort of arrangement may raise privacy issues.

It is important to see network charges in context. Network charging principles combine with flexibility markets (e.g. for fast response services) to create incentives for flexibility (such as that provided by battery storage). Getting the related markets for electricity products right is, if anything, more important than the network charging methodology. It is also the case that flexibility markets will to some extent adjust to changes in the network charging methodology (i.e. higher network charges on storage facilities, will raise the price of the response services that such facilities provide). This is true of efficient price discrimination

¹⁹ Developments in digital rights management have shown that this is possible in other sectors. We have now developed the technology to charge for every view of a page or a TV programme, regardless of whether it occurs using customer owned equipment. This has undermined the ability of owners of copies to trade them free of 'tax' (as is the case with books or CDs).

in general, such that as long as efficient deviations from headline prices are possible then efficient signals may be maintained.

Thus whatever the basis for published ('posted') network charges is, what matters is whether efficient deviations from those prices can be offered to DERs and other providers of flexibility to the network. Such discounts to posted prices can be selectively offered to flexibility providers who actually deliver services that are contractually useful to the network rather than incorporated into the posted prices directly. Thus the creation of formal flexibility markets – such as National Grid's new Enhanced Frequency Response (EFR) to provide frequency response within 1 second²⁰ – can target particular types of flexibility regardless of the basis of existing network charges. Similarly DNOs can be formally incentivised to seek to procure local DER provided electricity products, as in the State of New York REV initiative, which will see distribution utilities formally procuring services normally procured at the transmission level from DERs.²¹

This paper focuses on the charging models for network companies. However final charges for electricity service are determined by retail companies not network owners, these are the prices that most customers see and respond to. We should be clear that it is up to retailers as to the extent to which they wish to pass through the variations in network charges they incur to their retail customers.²² The extent to which this happens for half-hourly metered industrial and commercial customers is limited: a recent survey of customers in one DNO area in England found very few were actually exposed to any of the underlying variation in their network charges.²³ Thus sharpening network pricing signals may not make much difference to what final users do because of the limited degree of price pass through. While the GB energy regulator, Ofgem, could seek to regulate the pass through of charges, this would be to ignore the value that

²⁰ See <http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx>

²¹ State of New York Department of Public Service (2014).

²² A check of available retail offers on one price comparison site for my property on 14 March 2016 revealed that annual standing charges for electricity ranged from £61.90 to £100.01.

²³ Northern Powergrid (2015, pp.48-50).

retail customers place on simple to understand pricing structures and value of common national or regional prices to retailers.

The problem of network fixed cost recovery

Boley, and Fowler (1977, p. 31) discuss the nature of distribution costs: they suggest that they only vary with kW peak at each line voltage level and are mostly fixed with respect to kWh. Meanwhile connection to the electricity system by an end user confers significant option value to increase future consumption at any given moment, regardless of past or current use. This immediately suggests that use based charging does not adequately reflect the nature of underlying costs or the nature of connection benefits. One might imagine that the option value of the network might actually increase in the future as the network gives all users opportunities to respond to the impact of low carbon technologies. This is the case as low carbon technologies will induce more volatility in use due to own production of generation, use of electrical energy storage, electric heating and electric vehicles and hence increase the option value of the network itself. In general the costs of these services are made of fixed (core network), per peak kW connection and per kWh use elements, with the per kWh element being the smallest part of the three. This is especially the case if charges to cover system losses are actually bundled up with retail service (as they are in Great Britain), thus the per kWh distribution charge is essentially about wear and tear, not electrical losses.

The nature of the fixed costs is relevant. This is because costs can be fixed in two senses (1) with respect to time and (2) with respect to what is being varied.

With respect to the first of these, in the long run all costs are variable, but for the electricity network the long run is very long. Distribution assets can last 60 years (no doubt some are even older in some parts of the UK), while many poor

customers are elderly²⁴. Thus much of the network's costs today are fixed for the lifetime of many existing consumers, even if over time more cost reflective charging would give rise to the correct long run incentives for DER connection and, indeed, for configuring the entire network.

For instance, allowing DERs relatively favourable connection terms that redistribute network charges to households without DERs may delay the transfer of their financial benefits to poorer customers. This raises both horizontal and vertical equity issues because older, poorer customers will clearly benefit less than younger, richer customers. The dynamics of poverty are also important. Many individuals who start poor remain poor, this means that they are never part of households that will benefit from a reform where owners of distributed energy resources capture a disproportionate share of the total benefits from a more flexible system. In this case older network users will never see any of the benefits from a more flexible system.²⁵

With respect to the second of these, even if all existing network costs can be varied eventually, the issue is what do they vary with. The extent to which network costs vary with respect to each individual residential customer is small and if every customer simply paid their marginal costs of connection a significant part of the network would be unfunded. A focus on the costs and benefits of an individual DER project needs to be careful not to ignore that fact that marginal costs *per customer* (or per kWh, or per kW) are only part of the costs of a network.

A related idea is around whether to charge network customers long run marginal replacement costs. In theory this provides the right marginal signals, but in practice it leads to an-over recovery of revenue on current marginal costs given

²⁴ For England in 2013 around 18% of the households in fuel poverty are made up of individuals over 60 (DECC, 2015, p.25), though the number of people over 60 in fuel poor households is less than this (see Hills, 2012, p.61). 45% of English fuel poor households contain dependent children, and most of the people in fuel poverty live in such households.

²⁵ As Keynes (1924, p.80) said, '...this long run is a misleading guide to current affairs. In the long run we are all dead.'

that these are currently more expensive than historic assets (though this may change in the future). However this type of charging would still not solve the problem that geographical networks offering comprehensive access to all potential customers do have fixed costs which need to be recovered. Indeed, in recent years demand in kWh and kW has been falling per customer in many jurisdictions. If this is the case in general, then the long run marginal distribution system cost per kWh or kW is zero, while the system fixed costs still need to be recovered.

An important technical distinction can be made between fixed and sunk costs. Sunk costs refer to costs which cannot be recovered in any event, while fixed costs (which are not sunk) do not vary with output but are potentially recoverable. Most 'fixed' costs in the electricity system are also sunk and electricity customers will have to pay for them regardless of system demands to the extent that they are part of the regulatory asset base and hence subject to existing repayment guarantees, at least as long as there are any network customers.

Final electricity prices for residential and SME customers have traditionally not varied by location within a given electricity company service territory, though the variations between territories have been substantial²⁶. Final prices have also not varied by time of day. Electricity transmission charges have been bundled into per kWh use charges and electricity distribution charges have been recovered through a combination of a fixed and a variable charge. Thus overall the fixed charge has been low, even though the costs of serving a particular customer might actually involve more of an element of fixed cost recovery.²⁷ Core network fixed costs can be allocated differently between customer groups connected at different voltage levels. Differences in the basis of charging itself at

²⁶ Nillesen and Pollitt (2010) show electricity distribution costs can vary by a factor of 2 among different service territories within the same holding company.

²⁷ See Cluzel and Standen (2013) and Ofgem (2015).

different voltage levels may distort the choice of where to connect DERs.²⁸ These charging principles reflect the fact that decisions about charging are political (with a small ‘p’) and involve a concept of fairness which has deemed it more equitable to price actual use rather than fuller cost reflectivity (which might involve higher fixed costs and locational variation within service territories). The unacceptability of more cost reflective pricing also reflects the fact that taxpayers have directly (in public ownership) or indirectly (with regulatory revenue recovery guarantees) underwritten electricity investments, lowering the cost of capital, with the expectation of some general public benefit from the electricity network.

On such pricing, it is important to point out that the existence of fixed costs of any kind does not imply a more cost reflective pricing scheme is ‘optimal’, as we pointed out in the previous section. Fixed costs can be apportioned in a multiplicity of ways to individual consumers, most obviously by putting higher charges on richer consumers (a form of Ramsey-Boiteux pricing)²⁹. This has little efficiency impact (for the electricity system) if the reappportionment does not effect consumption. Thus it would be possible to apportion the recovery of fixed costs through charges by income, property value, kW connection capacity or another indicator of income (or ability to pay), which did not result in distortion of the use of electricity. Of course in the past the easiest proxy for income, available to utilities, has been electricity usage itself and hence recovering some fixed costs via kWh charges has been favoured (indeed via rising block tariffs in developing countries).³⁰ High fixed charges can be distortionary if they result in

²⁸ For instance the nature of DUoS charges for DG connected to the extra high voltage distribution network (under the EDCM) vs DUoS charges for DG connected at lower voltages (under the CDCM) is different in GB and may distort the decision of which voltage to connect at.

²⁹ See Ramsey (1927) and Boiteux (1971). Ramsey-Boiteux (or, simply, Ramsey pricing) pricing in the presence of higher social welfare weights on poor customers implies a modified form of the inverse price elasticity rule of fixed cost recovery (i.e. higher mark ups for fixed costs on more inelastic customers), which adjusts for the welfare weights. In the past rich electricity customers have also been price inelastic so that Ramsey pricing implies that they should pay much more towards the fixed costs than poorer customers. However in the future if rich customers with DERs become more price elastic this would imply that they should make less of a fixed cost contribution, than would have been optimal before.

³⁰ A survey of 16 EU countries showed that 13 recovered more than half of their residential distribution charges via kWh related charges. (see European Commission, 2015, p.114).

disconnections from the network (or non-connection in the first place), while high variable charges can distort consumption downwards. In the past the utility of electricity service has been so high (and the usage charges so low) that it clearly has not resulted in much disconnection (connection rates are close to 100%) or in much moderation of use among high-income consumers (price elasticities of demand are low). In the limit there is a risk that increasing fixed costs per se increases the incentive for complete disconnection from the grid (the so called 'utility death spiral').³¹ However the over-incentivisation of self-consumption is more likely to be a problem in Great Britain and indeed is a problem in some jurisdictions already, such as in Southeast Queensland, Australia, which we discuss below³².

If richer customers can be identified they can be charged more of the fixed costs, without much risk of them disconnecting. This is not to say that poorer customers are not sensitive to fixed costs. It might be possible to justify a new charge on owners of DERs, which is cost reflective or is a good way of collecting a share of fixed costs from them. One might imagine a maximum kW export charge for domestic and small and medium sized business customers, with PV. This does charge for a particular service and also is a good way to allocate fixed costs to these, richer, users. It might also mitigate any effect in reducing metered kWh import based charges. This is akin to charging broadband customers more of the network fixed costs for the fixed line telecoms network, as call volumes decline, partly as a result of increasing voice over the internet services (using broadband).

Residential consumers have also not, in general, been explicitly offered differential power quality. However it is true that lower income households may live disproportionately in less well served areas or may voluntarily accept lower power quality. Low income consumers on pre-pay meters can choose – though the choice is often forced upon them by circumstances - to self-disconnect if they

³¹ See Sioshansi (2016, pp. xxxi ff.),

³² Jones et al. (2016) also discuss the case of Hawaii, which has very high penetration of domestic PV.

don't top up their meters.³³ The quality of power offered to individual homes has not been variable below that the substation level (though rural households have had noticeably worse power quality than those in urban areas). In Great Britain, rural households experience greater costs of fuel poverty, in spite of having worse quality of service.³⁴ Worse power quality in rural areas has reflected the unwillingness to pay of electricity customers in general to improve rural power quality to the level seen in urban areas (which could be done only at very high cost).

It is important to point out that bad debt, insurance and policy costs are significant (in Great Britain these might be 20% of the final residential bill)³⁵. How to charge for these costs (and any related costs associated with long term arrears) is important. This is clearly relevant to the overall retail electricity bill, but it is also relevant to network charges, which also include elements of bad debt, insurance and policy costs (notably the Network Innovation Competition in Great Britain which adds around 1.5% to distribution system costs). The nature of bad debt cost recovery can reflect societal preferences, either to target costs back on to the customer groups with worse debt records (e.g. on to low user credit customers or pre-payment customers, exempting direct debit customers, which can be a form of statistical discrimination against low income customers who do pay on time) or to lift such costs off lower income groups onto richer customers. Insurance may be more valuable to higher income customers and actually less valued by poorer customers who would be prepared to have more exposure to cost volatility if it meant generally lower prices. Policy costs imposed on utilities are a form of hypothecated taxation (levied on electricity charges and ring fenced for energy policy). Hence it is clear that how this is recovered through electricity charges can be a more or less regressive form of taxation. In general it is common to recover most of these cost elements via the

³³ See Brutscher (2012).

³⁴ See Hills (2012, p.75).

³⁵ Ofgem data for April 2015 shows 16% of electricity bill is VAT, Environmental Charges and Carbon taxes and prices, this is after a refund of environmental charges of 2% and excludes insurance and bad debt costs. See <https://www.ofgem.gov.uk/publications-and-updates/charts-outlook-costs-make-energy-bills>

per kWh usage charge and this is usually the case in the UK. Though some individual policy costs can be charged on per customer basis³⁶. Whether customers are charged on a per kWh or a per kW peak capacity basis does not make much difference - for most customers - if there is a strong correlation between peak demand and units used.

The problem of how to recover subsidy costs has been a significant issue in the German electricity transition (EPRI, 2014). If the total subsidy cost is apportioned through per unit charges then clearly recovering subsidies (in Germany this is primarily done through the EEG charge) through metered consumption results in shift of subsidies towards households that have not taken them up. A new tax charge on own consumption of solar of 4.4c /kWh was proposed for industrial and commercial companies in Germany to partly correct the tax arbitrage incentive, but this was later dropped.³⁷

The question that arises in a world of significantly increased DERs is the extent to which the historic basis for electricity charging and apportioning system costs is valid in the future. There are very good reasons to think that the current basis might need to be changed in some way. The reasons are both theoretical and empirical, as we now have evidence on how unfair some of the existing charging can become if DERs take off. The potential for costs to be significantly reallocated quite quickly exists under a significant rapid expansion of DERs, raising the issue of affordability, as well as fairness. If there are distortions within the current charging structures it seems likely that encouraging more DERs on the basis of current cross subsidies will substantially favour richer consumers (who can afford the upfront capital costs to become prosumers). This is because investors in new DERs invest, at least in part, on the basis of arbitraging the current charging methodology.³⁸

³⁶ This was the case with the Carbon Emissions Reduction Target (CERT) scheme. See Chawla and Pollitt (2013).

³⁷ See <http://www.forbes.com/sites/greatspeculations/2014/01/29/germanys-proposal-to-tax-self-consumption-of-solar-power-could-hurt-panel-demand/#3e8e04506a7e> Accessed 16 March 2016.

³⁸ See analysis of drivers of residential solar PV uptake across the US in Kwan (2012).

A case study on in the impact of DERs and their implications for network pricing

Now we consider a case study of how network charging regimes can rapidly become unfit for purpose in the presence of a big uptake of particular DERs.

South Queensland in Australia has one of the highest penetration rates of domestic solar PV in the world. 22% of households had PV in 2014 (and 75% have air-conditioning).³⁹ *Distribution* charges in South Queensland are charged on the basis of 20% fixed cost and 80% per kWh. The massive increase in solar PV (from close to zero at the start of 2009) has resulted in a huge transfer of wealth and costs between customer groups. Solar PV consumers have lower metered consumption due to own production. This significantly reduces their share of the per kWh costs of the distribution system. Meanwhile the revenue cap regulation of the distribution charges means that the same revenue has been recovered as the number of units has fallen, thus per unit charges have risen and the distribution of their payment between different types of households has dramatically changed.

Simshauser (2014) analyses four types of household in this new situation: households with no PV and no air-conditioning (this is the poorest group); households with air-conditioning and no PV; households with PV and no air-conditioning; and households with PV and air-conditioning. He looks at how the distribution charging mechanism has shifted the payments and considers the impact of a more cost reflective charging regime where each household pays a fixed charge, a per kW peak charge and a variable per kWh charge which better reflects underlying costs. What he finds is that households with PV and air-conditioning have only a fractionally lower peak per kW usage relative to those with no PV but air-conditioning. Meanwhile households with air-conditioning and no PV currently pay less than they should towards distribution charges, given their relative cost of service. The impact is striking: the poorest group

³⁹ See Simshauser (2014).

without PV and air-conditioning currently pay 307 Australian dollars p.a. more (or c.£162⁴⁰, i.e. around 40% more) than those with PV and no air-conditioning (see Table 1). This reveals that the starting point of charging is already unfairly subsidising peaky users with air-conditioning AND that the system has rapidly become much more unfair with the high take-up of PV. A more cost reflective three part tariff scheme sees those with PV and air-conditioning paying 28% more than at the moment and those without both paying 15% less (with the result that the poorer households pay around 180 AUD (£95) less). Simply put: the relationship between kWhs and kW peak observed prior to the arrival of PV has fundamentally changed, such that kWhs are a poor proxy for kW peak demand.

⁴⁰ 1 AUD = 0.53 GBP as of 16 March, 2016.

Table 1: Differences in Network Charges for Residential Consumers
in South Queensland

	Household A	Household B	Household C	Household D
	No air-con	Air con	No air-con	Air-con
	No Solar PV	No Solar PV	Solar PV	Solar PV
Maximum Demand (kW)	1.41	2.14	1.40	2.09
Metered import (kWh)	6253.4	7560.6	3820.1	4707.1
Solar Export (kWh)	0	0	2259.1	1838.8
Gross Demand (kWh)	6253.4	7560.6	6253.4	7560.6
Number of customers	283849	694643	26151	235357
% of customers	23%	56%	2%	19%
Base Network Tariff	\$1006.14	\$1171.37	\$698.57	\$810.69
Differences	A-C	B-D		
	\$307.57	\$360.68		

Source: Simshauser (2014).

The implications for other jurisdictions (such as Great Britain) are two-fold.

First, some consideration must be given to whether the starting charging methodology is efficient and fair. It could be that the system already favours richer consumers or certain types of network user (e.g. DG generally) who do not bear either the efficient or fair share of the total system distribution (and transmission) costs.

Second, going forward does the apportionment of charges between fixed, per kW peak and per kWh use of system charges need to be changed to being more cost reflective?⁴¹ And related to this, does the advent of a significant new technology at a particular voltage level on the network mean that a new type of charge needs to be introduced at that voltage level (e.g. kW peak export tariff)?

Otherwise the danger is clear: a high take-up of DERs will result in a large redistribution of system payments which does not reflect the true costs of serving each consumer, the drivers of historic costs and/or a fair allocation of

⁴¹ See Cluzel and Standen (2013, p.25), for domestic customers distribution charging is around 85% per kWh and rest fixed per day.

sunk cost recovery. For given customer classes (e.g. households, and businesses connected at different voltages), this could massively change the current allocation of fixed costs between them. As we noted earlier promotion of DERs may become an opportunity for a form of ‘tax’ arbitrage from poorer to richer households and businesses.

The problem of over-incentivisation of DERs

Some DG and DSM behind a given distribution system substation (node) may be beneficial, while too much may involve diminishing (indeed negative) marginal system benefits. Ideally the system would procure the socially optimal quantity and do so at a competitive price. What needs to be avoided is investment up to the point at which private marginal returns are still positive but social marginal returns are negative.

Theory and evidence suggests that as subsidy rates drop for DERs the impact of network pricing distortions, such as those discussed above, in driving inefficient self-consumption with negative implications for other grid users will increase.

Designing a network pricing scheme that supports the procurement of the ideal amount of distributed energy resources in aggregate, let alone at any given node of the distribution system, is clearly very difficult. The potential for over-incentivisation is large, especially in the light of the history of subsidies to residential PV. Given that other technologies (such as domestic batteries or responsive EV charging) may have the same level of general public support or learning benefit as PV, avoiding such over-incentivisation of local response is important.

Conclusions

The principles of how to charge for electricity networks are complicated. We have discussed how there are several different models on which network charges could be based.

Any charging methodology for an electricity network has to deal with the issue of fixed cost recovery. This is effectively a tax, which needs to be levied on network users to adequately finance a network, which has option value for all connected users. The 'tax' rate on an individual network user could be higher or lower, but network fixed costs need to be recovered in aggregate and this will lead to some clear incentives on heavily taxed users to make investments driven by tax avoidance advantages.

The rise of DERs offers increased opportunities to exploit the existing system of network charges in ways that were not originally envisaged. Fundamentally changing the basis of charging may be necessary. We discussed an example from Australia that showed how quickly the existing charging basis, based mainly on kWhs, could become a significant issue. One could envisage rapid uptake of PV, EVs or distributed storage posing such charging problems at either the household or business customer level. It seems highly likely that poorer customers (in all classes) would be disadvantaged by their inability to invest in the sort of flexibility that might be required of customers in the future to keep their bills down.

A final significant issue is that new investors in flexibility capture such a large share of the system benefits that they produce that no net benefit to the existing customers. The electricity network has been financed by its existing customers - it represents a significant sunk cost incurred by and underwritten by them. Going forward, there must be some general advantage to increasing DERs on the electricity system, thus it would be reasonable to expect new DERs to prove that they can deliver wider system benefits, not simply cannibalise existing network revenue. A worst-case scenario is that an increasingly flexible system is one characterised by no lower costs, relative to the status quo, but with a much worse distribution of payments between network users.

The good news is that new uses of the network creates opportunities for reallocating charges to new users and away from existing users who may be poor

and/or vulnerable. It may also be that solutions as to how to change the charging basis are easily to hand, because we are simply seeing the extension of well-known issues from higher to lower voltages on the network. Where this latter phenomenon is the case, we may straightforwardly need to introduce new dimensions to network charging (such as per maximum kW export / import tariffs) which already exist at the transmission level at lower voltages. However electricity regulators would be well advised to carefully assess the impact of any potential changes to the basis of charging under a large range of potential DER uptake scenarios as part of their future proofing of existing charging methodologies. Such scenario analysis should examine permutations of both the basis of charging (i.e. fixed, per kW import/export, per kWh import/export etc.) and the uptake of multiple DER technologies (i.e. PV, EVs, distributed storage, air source heat pumps etc.).

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